86-686

No. _____

Supreme Court, U.S.
FILED
OCT 27 1986
JOSEPH F. SPANIOL, JR.
CLERK

SUPREME COURT OF THE UNITED STATES

OCTOBER TERM 1986

HYDROPOOL and COGENERATION SERVICES, INC., Appellants,

vs.

CALIFORNIA PUBLIC UTILITIES COMMISSION and PACIFIC GAS & ELECTRIC COMPANY, Appellees.

ON APPEAL FROM THE SUPREME COURT OF CALIFORNIA

APPENDICES TO JURISDICTIONAL STATEMENT

VOLUME I (of 3 Volumes)
Appendix A through F

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128 pp

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ORDER DENYING WRIT OF REVIEW

S.F. No. 24966

IN THE SUPREME COURT OF THE STATE OF CALIFORNIA

IN BANK

Cogeneration Services Incorporated,

Petitioners

v.

Public Utilities Commission, Respondent;

Pacific Gas and Electric,

Real Party in Interest

Petition for writ of review DENIED.

Mosk, J., is of the opinion the petition should be granted.

/s/

Chief Justice

Decision 85-09-058 September 18, 1985

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Investigation on the Commission's own motion into the transmission system operations of certain California electric corporations regarding transmission constraints on con-generation and small power production development.	)	I.84-04-077 (Filed April 18, 1984)

(See Decisions 84-08-037 and 85-01-038 for prior appearances.)

Additional Appearances

Ann P. Cohn, David N. Barry, III, and Jennifer Moran, Attorneys at Law, for Southern California Edison Company, respondent.

Graham & James, By James Squeri, Attorney at Law, for Union Oil Company of California; Neal A. Johnson, for California Waste Management Board; Robert Logan, for himself; Alicia Torre, for International Power Technology; and Margaret Rueger, for U.S. Windpower, Inc.; interested parties.

O P I N I O N

I. Summary

By this order, we close an investigation into transmission limitations in utility systems which may affect the development of

Qualifying Facilities(QF). We find that Pacific Gas and Electric Company (PG&E) may have significant constraints in its northern system. The other two utilities, Southern California Edison Company (Edison) and San Diego Gas & Electric Company (SDG&E), should not have significant transmission constraints. [2]

II. Background

On April 18, 1984, the Commission issued Order Instituting Investigation (I.) 84-04-077 to examine alleged transmission constraints in PG&E's transmission system which would affect QF development. The Commission also wanted to assess the extent of any limitations in other utilities' transmission systems which would affect QF development.

The respondent utilities filed statements of anticipated limitations on their bulk and area transmission systems over the next ten years which may affect QF development. In

these statements,only PG&E predicted that it would have significant constraints in its northern transmission system.

After submission of the utilities' statements, the Public Staff Division (staff) held several workshops at which an interim solution was developed for PG&E's northern transmission system, a milestone procedure for QF development was formulated, and transmission cost allocation approaches were discussed. (See Decision (D.) 84-08-037 and D.85-01-038.) The participants in the staff's workshops were able to resolve several issues and thereby reduce the need for formal hearings.

Hearings were held from April 8-12, 1985 on three subjects: utilities' transmission constraints, cost allocation approaches, and access to the Pacific Northwest-Pacific Southwest 500 kilovolt (kV) Intertie (Intertie) under the terms of the interim solution (see Appendix A). PG&E, Edison,

SDG&E, Sante Fe Geothermal, Inc. and Ultrasystems, Inc. (Ultrasystems), Indepentent Energy Producers (IEP), Cogeneration Services, Inc. - Hydropool (Hydropool), and staff presented witnesses. Concurrent briefs were filed by May 24, 1985.

[3]

III. Transmission System Limitations

A. PG&E's Transmission System

1. Transmission Constraints

James H. Malinowski, PG&E's Chief Transmission Planning Engineer, testified that transmission capacity is not currently available in some areas of PG&E's northern system. Malinowski stated that from 1980 to 1984, the megawatts (MW) of signed QF contracts increased from 204 MW to 6,593 MW. Malinowski asserted that this unexpected increase in QF power exceeded available transmission capacity in its northern system.

According to Malinowski, the availability of transmission capacity is

dependent on existing and future load levels as well as existing and future generation. In PG&E's northern area,generation consists of area hydro, imports, geothermal, Rancho Seco, other entities, and QFs. This anticipated generation will exceed the expected load during certain hours of each year for the next ten years.

In PG&E's southern area, the company is monitoring the development of large enhanced oil recovery projects to determine if capacity constraints will emerge.

Malinowski sponsored the following table showing that the northern system already has a resource-load imbalance:

[4]

Load, Excluding System Line Losses (MW)
and
Resources, Excluding Northwest Import (MW)

Main Area	Installed Capacity	Typical Resources On Line	Peak Load	Surplus Resources	Resources Needed to Meet Load
Northern	8,892	7,290	5,328	1,962	-
Bay Area	4,670	2,232	5,540	-	3,308
Southern	7,290	5,366	5,062	304	-

Northern Area includes SMUD and Humboldt, Shasta, Colgate Drum, De Sabla, North Bay, Sacramento, and Stockton Divisions.

Bay Area includes San Francisco, East Bay, and San Jose Divisions.

Southern Area includes MID, TID, and San Joaquin and Coast Valleys Divisions.

Malinowski stated that most of the northern area's 1,962 MW of surplus resources will be transmitted to meet Bay Area load. According to Malinowski, this transfer of power will fully load some bulk transmission lines. As a result, any additional QF power in the northern area would cause these transmission lines to overload.

PG&E has conducted a study to determine which lines would be overloaded during the summer peak and the spring partial peak periods. This study showed that the existing bulk transmission system had no available capacity for firm deliveries of QF power. Malinowski testified that under normal conditions the following 230 kV lines and 500 kV capacitors would be overloaded:

a. Gold Hill-Tesla

b. Ranch Seco-Tesla

c. Bellota-Tesla Nos. 1 and 2

d. Tracy-Tesla Nos. 1 and 2

e. Vaca-Dixon-Contra Costa Power Plant (CCPP) Nos. 1 and 2

f. Vaca-Dixon-Moraga Nos. 1 and 2

g. Round Mountain-Table Mountain 500 kV series capacitors.

[5] Malinowski also testified that constraints exist in several area transmission systems within the northern system. In most of these areas, which are rural or suburban, the load and expected load growth is small compared to urban areas. Consequently, existing transmission lines are of relatively low capacity. In addition, the area generation often exceeds the area load. The following table shows the available transmission capacity in the northern areas:

Sub Area	Load (MW) Maximum (A')	Load (MW) Minimum (A)	(MW) Existing and Planned Generation (B)	(MW) Maximum Export (C)=(B-A)	(MW) Existing Transmission Capacity (D)	(MW) Available Transmission Capacity (E)=(D-C)	(MW) Potential QF Generation**** Allocated	(MW) Potential QF Generation**** Wait List
Humboldt Division Includes Trinity County - Shasta	130	40	128	88	88	0-90*	90.0	136.5
Pit 1 System	19	5	106	101	106	5	4.5	40.0
Cedar Creek 60 kV Area	3	1	7	6	16	10	27.0	0.5
Battle Creek 60 kV Area	3	2	38	36	36	0	4.5	4.0
Caribou 60 kV Area	75	34	78	44	84	40	70.0	20.0
Feather River Area	0	0	339**	339	390	51		
Paradise 60 kV Area	40	16	38	22	37	15	0.5	63.0
Colgate 60 kV Area	52	17	417	365***	365	0	20.5	12.0
North Bay North	220	132	245	113	113	0	20.0	59.0
North Bay South	865	519	2,132	1,613	1,613	0	382.0	862.5
Drum Division	4	2	174	172	172	0	20.0	7.3

* 90 MW available if Humboldt Bay Units 1 and 2 are backed down.

** Includes 44 MW of import from the Caribou 60 kV area.

*** B - A'

**** List as of February 8, 1985

[7] 2. Transmission Upgrades

Malinowski testified that two groups of transmission upgrades to its bulk transmission system have been identified. The first group will provide transmission carrying capability for an additional 1,150 MW of QFs, the QFs interconnecting under the terms of the interim solution. (See D.84-11-123 modifying D.84-08-037.) These bulk upgrades, their estimated cost, and expected operating dates are as follows:

Potential Bulk Transmission Upgrades
For First 1,150 MW of Added QF Power

	Estimated Cost (in Million of 1984 Dollars)	Expected Operating Date
String a second 230 kV circuit from Gold Hill to Tesla.	3.4	March 1988
Add about 500 MVARS of shunt capacitors.	8.0	June 1989
Build an additional 230 kV DCTL from Bellota to Tesla.	18.2	December 1989
Rebuild the Vaca-Dixon-Contra Costa 230 kV DCTL.	37.2	December 1990
Rebuild the Vaca-Dixon-Moraga 230 kV DCTL.	55.4	June 1991
Add second 500/230 kV transformer bank at Tesla.	15.5	June 1992
Total	137.7	

The second group of bulk upgrades will accommodate the transmission requirements of an additional 2,000 MW of QF power in the northern area. Approximately 2,000 MW of QFs are on a PG&E waiting list for transmission capacity in the northern area. These upgrades and their estimated cost are as follows:

Potentail Bulk Transmission Upgrades
For Another 2,000 MW of Northern QF

	Estimated Cost (in Millions of 1984 Dollars
Upgrade Round Mountain series capacitors.	$ 26.1
Build new Table Mountain - Tesla 500 kV line and install series capacitors and transformer banks at both ends.	154.8
Replace conductors of Weber -Tesla section of the Bellota-Tesla 230 kV DCTL with SSAC.	7.5
Add two circuits of two 3,500 kcmil cables at the underground section of Castel Rock Junction-Lakeville line.	5.4
Rebuild the Lakeville-Vaca-Dixon 230 kV DCTL with 2-1113 kcmil AAL conductors.	27.8
Total	$221.6

Finally, Malinowski described planned area transmission upgrades as follows:

Area Reinforcements

Area	Transmission Capacity (MW) Available	To Be Added	Estimated OD	Cost $ x 1000	$/Kilowatt (kW)**
Pit 1	5	100	1988	9,000	90
Cedar Creek	10	38	1987	4,400	116
Battle Creek	0	25	1987	2,000	80
Caribou 60 kV & Feather River	40	100	1990	13,500	135
Paradise	15	50	1987	3,000	60
Colgate	0	30	1988	2,500	83
North Bay North	0	80	1988	5,500	69
North Bay South	-	-	-	-	-

* In 1985 dollars.

** $/kW of area transmission capacity added - excludes $119/kW of bulk transmission costs.

[9] U.S. Windpower, Inc. (USW) in its brief stated that PG&E has provided incomplete information on transmission constraints in the Altamont Pass area. Malinowski during cross-examination testified that there are transmission constraints in this area. He further stated that there is a waiting list of at least 700 MW of QFs desiring transmission capacity in this area.[1] USW observes that PG&E has not provided examples of planned upgrades which will relieve these constraints in Altamont Pass.

B. Edison's Transmission System

Edison does not expect to have any transmission limitations during the ten-year period ending in 1994 that will constrain QF

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1 By letter dated July 3, 1985, counsel for PG&E informed the administrative law judge (ALJ) that certain transmission lines in the Altamont Pass area have been "uprated" to accommodate most of the QFs on the waiting list.

development. E. M. Helm, Senior Planning Engineer, testified that the company's Fall 1984 Generation Resource Plan has 3,250 MW of renewable and alternate resources for the period 1985-1994. Helm stated that Edison has planned to develop its transmission system to accommodate these QF facilities. Accordingly, Edison does not expect any major difficulty in integrating QFs into its resources.

C. SDG&E's Transmission System

SDG&E also does not anticipate any bulk transmission constraints in its service territory which will limit QF development over the next ten years. Ronald Erdman Busher, Supervisor of Transmission Planning, identified two areas which have potential limitations: Boulevard and Warner Springs. However, Busher further testified that the actual QF development in these two areas will not surpass the line capacity in these areas. Thus, SDG&E believes there also are no significant area transmission limitations in its system.

[10] IV. Transmission Cost Allocation

After studying the utilities' evaluations of their transmission systems, the parties examined transmission cost allocation approaches. The staff held a workshop to see if the parties could agree upon a basic allocation of most transmission upgrade costs to utilities and their ratepayers. General agreement was reached; however, minor differences arose during the hearings.

The staff, through its witness Julian Ajello, stated that utilities have the responsibility for anticipating the growth of QF resources. Utilities also must plan and construct adequate transmission capacity. Ajello emphasized that QFs are a significant portion of utility resource plans and therefore must be considered in utility transmission plans. Ajello further stated that the cost of transmission capacity which

has multiple purposes is a legitimate ratepayer expense. Thus, staff believes the cost of transmission lines or upgrades should be allocated to ratepayers unless the transmission facility does not serve multiple purposes.

PG&E believes that the reasonable cost of nondedicated facilities necessary to take QF power should be paid by ratepayers. However, PG&E's witness Malinowski asked the Commission for guidance on the reasonableness of a transmission facility cost. Malinowski suggested that a cost cap of about $150/kW could be used as a guideline for determining reasonable area transmission costs. Malinowski explained that the company really was seeking Commission approval of the concept of a cap as a guideline and not for the fixing of a particular cap.

Edison urges the Commission to approve the company's current allocation under which

the QF pays for transmission facilities which are directly related to or required by QFs. If an upgrade is not directly required by or solely beneficial to a QF, the QF has no cost responsibility. In other words, as Edison's witness [11] Helm stated, if a transmission facility has system benefits, then the QF need not pay for it.

SDG&E asserts that its analysis of a transmission facility's cost is the same for QFs, all other resources, and customers. SDG&E analyzes the following factors for each transmission line:

1. Future system growth needs
2. System security and reliability
3. Emergency support
4. Economy energy access
5. Transmission losses
6. Transfer capacility
7. Firm resources at system peak conditions
8. Cost effectiveness

SDG&E believes that each transmission line or upgrade must be evaluated under the above criteria. SDG&E submits there is no need for the Commission to change the company's existing transmission planning method.

IEP asserts that it is the utility's obligation to plan and to build transmission upgrades or lines when there are benefits to ratepayers. IEP submits that as a general rule most transmission upgrades or lines will have system benefits and therefore should be paid for by the utility's ratepayers.

IEP asks the Commission to adopt a cost cap to provide some certainty about QF access to transmission. IEP proposes that any transmission project undertaken at an estimated expense below the cost cap would be presumed reasonable. In this way, IEP asserts a QF will have an indication of what transmission lines should be built by the utility to accept QF power.

IEP's witness Jan Hamrin testified that a cap of about $180/kW is appropriate for all utilities' area transmisison lines. Hamrin agreed with PG&E's witness Malinowski that all bulk [12] transmission lines have generalized system benefits. Accordingly, a cost cap for bulk transmission lines is unnecessary since the ratepayers always are responsible for these lines.

Ultrasystems submits that a cost cap for transmission projects should not be adopted. Ultrasystems states that the adoption of a cost cap would assume a long-run avoided cost for the utility which has not yet been determined. Ultrasystems argues that until the long-run avoided cost methodology is determined, a transmission cost cap cannot be adopted.

Pacific Lighting Energy Systems (PLES) agrees that QFs should not be responsible for transmission facilities which have system-wide benefits to customers. PLES points out that

this general concept is expressed in several ways by the different utilities. Accordingly, PLES recommends that the Commission adopt Edison's language as the standard for all utilities to avoid different applications by the utilities.

In addition, PLES submits that a cost cap, if adopted, should be used only as a general guideline in assessing the reasonableness of a transmission project. PLES emphasizes that a QF should have the right to come to the Commission if a utility refuses to build a transmission upgrade or line because its cost exceeds the cost cap.

V. Refund of Interim Solution 1.7 Mills/ Kilowatt-hour (KWh) Assessment

PG&E and staff recommend that since QFs should not be held responsible for the cost of most transmission upgrades, 1.2 mills/kWh should be refunded from any payments received under the terms of the interim solution. In addition, the 1.7 mills/kWh charge should be

reduced to .5 mill/kWh prospectively. The interim solution provided that 1.2 mills/kWh of the 1.7 mills/kWh is refundable if the Commission determines that QFs have no cost responsibility. However, [13] PG&E believes the interim solution is unclear as to what QFs should pay after the Commission's decision is issued. PG&E and staff assert that it is equitable for QFs to continue paying .5 mill/kWh over the life of the contracts since the QFs are receiving the benefits of transmission access before the transmission upgrades and lines necessary to accommodate their deliveries are completed.

The QFs maintain that no assessment is appropriate after the Commission issues a decision finding that QFs usually will have no cost responsibility. The QFs assert that the Commission cannot in "good conscience" assess a continuing charge of .5 mill/kWh, no matter how small, after it determines that QFs are not responsible for transmission upgrades or lines.

VI. Discussion

A. QFs generally are not responsible for the cost of transmission upgrades or lines.

QF deliveries are a significant part of each utility's resource plan. Accordingly, utilities must plan for and otherwise enable QF facilities to interconnect with their transmission systems in an expeditious manner. We recognize that both the diversity and the number of emerging QFs in PG&E's system have created new problems for the company's transmission planners. However, PG&E along with the other utilities must learn to facilitate the addition of QF power as it already has learned to accept power deliveries from all other resources.

The parties have agreed among themselves that QFs should not be responsible for the cost of transmission facilities which serve multiple purposes. The parties find since the ratepayers in the past have paid for

these transmission facilities, the ratepayers should continue to absorb the cost as long as the transmission facility has system-wide benefits. A QF is responsible only for interconnection and other facilities that have no system-wide [14] benefits and are solely beneficial to the QF. This approach eliminates the need for a difficult cost allocation among the various users of a transmission facility.

System-wide benefits can mean many things as shown in SDG&E's list of factors affecting its transmission planning. Thus, we believe that nearly all transmission facilities arguably may have some system-wide benefits. Bulk transmission lines by definition have system-wide benefits. And nearly all area lines probably will have some system-wide benefits. Thus, QFs will asssume cost responsibility only on the rare occasion that an area line lacks any perceptible system-wide benefit.

On occasion, a transmission facility's cost may outweigh its system-wide benefits. In this event, the QF perhaps should be responsible for any excessive cost caused by the interconnection of its facility to the utility's system. A rigorous cost-benefit analysis, however, touches upon many as yet undefined criteria. We have yet to determine a long-run avoided cost methodology for QFs. We have not yet adopted consistent energy reliability criteria for all utilities. The cost of transmission service is just one piece to the puzzle of properly valuing QF power. Thus, for the moment, we will allow utilities to follow the general principle that as long as a transmission facility has system-wide benefits, the utility's ratepayers are responsible for the prudent and reasonable cost. The QF is responsible only for interconnection cost and other special facilities which have no system-wide benefits. Refinement of this principle must await our determination in the long-run avoided cost proceedings.

B. A transmission cost cap can be a useful guideline for utilities and QFs.

PG&E has asked for Commission approval of the concept of a cost cap. PG&E's witness Malinowski carefully explained that a cost cap would help PG&E in its transmission planning for QFs as a [15] benchmark of costs that will be absorbed by ratepayers. However, Malinowski went on to say that PG&E would continue that same analysis in its transmission planning that would occur without the guideline of a cap. The concept of a cost cap is attractive but the calculation of the level of a cap involves many of the previously mentioned criteria which are not well-defined. To the extent a cost cap will be added to PG&E's existing analysis and will not become an accepted substitute for the usual study of a proposed transmission facility, it may refine and improve PG&E's current transmission planning process. Thus, we will permit PG&E to

develop a cost cap and use it as a tentative guideline in its planning.

We caution PG&E that its calculation of a cap may be examined by QFs and staff. The level of a cap may vary greatly depending on the selected assumptions. The information underlying the derivation of any cap should be shared with all interested parties. A QF may, by complaint to the Commission, allege that a selected cap is unreasonable and thereby bring the reasonableness of the utility's calculation into issue.

C. A .5 mill/kWh assessment should continue until the transmission upgrades associated with the interim solution are completed.

Under the terms of the interim solution, 1.2 mills/kWh of the 1.7 mills/kWh assessment is refundable if the Commission finds the QFs have no cost responsibility for transmission upgrades. Since we have

determined that QFs have virtually no responsibility for transmission facilities with system-wide benefits, 1.2 mills/kWh clearly should be refunded.

Since QFs participating in the interim solution will receive access to transmission before the associated upgrades are completed, we find it is reasonable to continue a .5 mill/kWh assessment until the transmission upgrades associated with the interim solution are completed. The payment is a minimal offset to [16] the potential diseconomies identified by PG&E. However, since PG&E has stated that the diseconomies will end once the upgrades are completed, there is no reason to continue the assessment beyond the completion date. Therefore, as each upgrade is completed, the QFs whose delivery was constrained by that line no longer should be liable for a .5 mill/kWh charge.

D. PG&E's Petition to Modify the Interim Solution to Exclude the Intertie should be granted.

The ALJ issued a ruling in which he concluded that no further hearings were necessary on QF interconnection to the Intertie under the terms of the interim solution (see Appendix A). We hereby affirm the ALJ's ruling and grant PG&E's Petition to Modify D.84-08-037. We find after reviewing the evidence that there is an adequate basis for excluding the Intertie from the terms of the interim solution. We do not reach the larger question of whether and, if so, under what conditions QFs ever should have access to the Intertie.

Instead, we find that a separate proceeding should be established to consider the broader issues of out-of-state QF power in the context of how to utilize our scarce interstate transmission resources for the

maximum benefit of the ratepayers. Issues to be addressed in that proceeding will include, but will not be limited to:

1. the extent to which unlimited power purchases resulting from interconnection of out-of-state QFs would cause displacement of economy energy, especially from the Northwest;

2. the feasibility of developing pricing and curtailment options to protect ratepayers from paying uneconomic prices to out-of-state QFs should we determine that out-of-state QFs ought to be given an opportunity to serve the California power market;

3. a comparison of California and non-California avoided costs, to provide a perspective on the relative attractiveness of California as a market for out-of-state QF power; and

[16a] 4. an evaluation of the circumstances, if any, under which it would be appropriate to make standard offers available to out-of-state QFs and the form that such offers should take.

By examining the problems of how to deal with out-of-state QFs in a generic proceeding, we will avoid the risk of reaching a conclusion on these issues based on the necessarily incomplete record and limited perspective raised in the current proceeding in which the focus was exclusively on HydroPool's projects. The question of whether HydroPool should be granted access to the Intertie will appropriately become part of the more general question of the terms and conditions, if any, under which out-of-state QFs should be allowed interconnection.

Findings of Fact

1. PG&E expects to have significant constraints in its northern transmission

system during the next ten years which may affect QF development.

2. Edison and SDG&E do not expect to have any significant transmission constraints over the next ten years.

3. The parties agree that transmission facilities which have system-wide benefits should be paid for by ratepayers.

4. The parties agree that transmission facilities which lack system-wide benefits and are beneficial only to the QF should be paid for by the QF.

[17] 5. Bulk transmission lines have system-wide benefits and should be paid for by ratepayers.

6. Nearly all area transmission lines will have system-wide benefits and should be paid for by ratepayers.

7. A rigorous cost-benefit analysis of a transmission facility is dependent on criteria yet to be defined in other Commission proceedings.

8. QFs participating in the interim solution should be refunded 1.2 mills/kWh but should continue to pay a .5 mill/kWh assessment until the transmission upgrades associated with the interim solution are completed.

9. The Intertie is different from other constrained transmission lines in PG&E's northern system since (1) QF interconnection to the Intertie may cause greater displacement of economy power than QF interconnection to other lines, (2) QF interconnection to the Intertie will affect PG&E's negotiations of power purchase deliveries over the Intertie, and (3) PG&E has never represented to QFs that interconnection to the Intertie would be acceptable without price adjustments or curtailment provisions.

10. This investigation should be closed so that the parties may devote their attention and resources to the pending OIR 2 proceedings and the determination of long-run avoided cost for QFs.

Conclusions of Law

1. Ratepayers in the past have paid for transmission facilities which serve multiple purposes. Ratepayers should continue to pay for transmission facilities which have system-wide benefits.

2. QFs participating in the interim solution should continue to pay a .5 mill/kWh assessment until the transmission upgrades which are intended to eliminate operating diseconomies are completed.

3. A rational basis exists for excluding the Intertie from the terms of the interim solution.

[17a]

4. The Commission should establish a separate proceeding to investigate the unresolved questions relating to the desirability of purchasing power from out-of-state QFs and the terms and conditions under which any such purchases should take place. The issue of

whether HydroPool should be granted interconnection for its projects should be taken up in this new proceeding.

[18]

O R D E R

IT IS ORDERED that:

1. Utilities shall required QFs to pay only for transmission facilities which lack system-wide benefits and are beneficial only to QFs.

2. QFs participating in the interim solution shall be refunded 1.2 mills/kWh and shall continue to pay .5 mill/kWh until the transmission upgrades associated with the interim solution are completed.

3. Pacific Gas and Electric Company's Petition to Modify D.84-08-037 is granted to exclude the Intertie from the terms of the interim solution.

4. The Legal Division shall prepare an order instituting investigation to evaluate the desirability of purchasing power from out-of-state QFs and the terms and conditions under which any such purchases should take place.

5. I.84-04-077 is closed.

This order becomes effective 30 days from today. Dated September 18, 1985, at San Francisco, California.

DONALD VIAL
President

VICTOR CALVO
FREDERICK R. DUDA
Commissioners

I will file a written dissent.

/s/ WILLIAM T. BAGLEY
Commissioner

Commissioner Priscilla C. Grew, being necessarily absent, did not participate.

Excerpts from California PUC Decision
No. 82-01-03,
dated January 21, 1982

OIR 2 /ALJ/cm/km

O P I N I O N

[1a] Summary

This decision orders the major California electric utilities to file standard offers for power purchases based on avoided cost principles. These offers shall be available to all cogeneration and small power facilities that qualify under the Federal Public Utility Regulatory Policies Act of 1978. The decision finds that avoided cost pricing will promote the maximum efficient development of cogeneration and small power resources, diversifying the energy supply in California and reducing the state's oil dependence.

The standard offer gives qualifying facilities (QFs) a series of options to tailor contracts to meet their varied needs.

Within 45 days, the utilities are ordered to file the following standard offer options which will become effective upon a compliance review by the staff. These options are:

- Facilities providing as-available electricity (energy delivered without a long-term contract) will receive an as-available energy and an as-available capacity payment in ¢/kWh, varying by time of delivery. The as-available price will be based on a short-run avoided cost methodology, with capacity reflecting an estimate of the utilities' shortage cost (pp. 30-56).

- QFs which agree to certain performance standards may receive a firm capacity payment, rather than an as-available payment. The firm capacity payment is available in $/kW/year, and may be contracted for and levelized for up to 30 years. The firm capacity payment, like the as-available payment, is based on a shortage cost methodology. Firm capacity contracts will also include payments for energy (pp. 57-64).

[1b]

The decision orders utilities to file within 90 days proposals for three other option which will become available after additional hearings. These options are:

- Energy payments may be fixed in advance for up to five years for QFs which agree to commit to provide energy over the term of the contract. This energy payment may be tied either to an as-available or firm capacity option. Payments will be based on projected variable operating costs of the utilities (p. 51).

- A long term contract, based on a utility's long-run resource plan for both energy and capacity shall be available for QFs. This offer will be based on a long-run avoided cost concept (pp. 64-68).

The decision also establishes guidelines for the standard offer relating to interconnection costs, refusal to purchases, line losses and other contract terms.

The decision allows utilities to file for review of non-standard contracts with this Commission for two years after the effective date of this decision.

This decision also sets standards for rates for sale of power to QFs. Standby rates currently in effect are found reasonable for all QFs on demand schedules, and will be updated in general rate cases in proportion to increases in per kW capacity costs. They are eliminated for QFs who achieve an 85% on-peak capacity factor. Alternate standby rates are adopted for QFs on time-of-use rates. A time frame for planning periods of scheduled maintenance is adopted and scheduled maintenance rates are set at regular tariff

rates. Added demand charges are waived for maintenance fitting utility schedules. Interruptible service offerings are made available for all large QFs.

* * *

[23]

C. The Standard Offer

1. Introduction

We have previously referred to the "standard offer". This is the expression widely used by the parties to describe the terms and conditions associated with the utility's obligation to purchase from a QF at the utility's avoided cost. The standard offer is available to all QFs, and represents a complete transaction, including prices, interconnection requirements, and other relevant factors. A central aspect of all such offers will be the standard rates for purchase.

Section 292.304, paragraph (c), provides, in part:

> "(1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.
>
> "(2) There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts."

[24]

Standard rates for purchases may differentiate between QFs using various technologies on the basis of their differing supply characteristics and must be consistent with the factors listed in Part IV, A, above. As discussed below, in this decision we provide for standard rates for QFs of 100 kW or less and for more than 100 kW. The rate has relevance only in relation to the mutual obligations of the parties. In this decision we consider the nature and extent of such obligations. The result is the standard offer.

The standard offer has particular significance in terms of the existing and anticipated ratemaking treatment to be afforded utility purchases of energy and

capacity provided by QFs. Purchases under the standard offer are per se reasonable and a utility's expenses for such purchases are recoverable in the same fashion as other purchased power expenses (in ECAC proceedings, for the larger utilities) without further review. Purchases at rates, terms, or conditions other than the standard offer are recoverable through ECAC or other appropriate procedures subject to a showing of reasonableness. Because of the different degrees of risk for the utility, there is widespread interest in whether the Commission will review nonstandard contracts prior to their becoming effective.

In adopting the parameters for rates that will be part of the standard offer, we are establishing a definition for a utility's avoided costs to be applied when purchasing energy from qualifying facilities under the terms and conditions of a specified standard

contract. To facilitate discussion of the specific issues related to avoided costs as raised in this proceeding, we will first make some general observations.

[25] The Commission has found in recent years that avoided cost (or marginal cost) pricing has significant benefits when applied to ratemaking. Avoided costs reflect the added costs to a utility of producing an additional unit of electricity. When marginal costs are used as the basis of rate design, consumers receive an efficient price signal. When adopted for purchasing electricity from third parties, the price encourages full economic development of those resources. Avoided cost pricing parallels the prices that would be established in a competitive market, providing many of the incentives for efficient resource allocation that a competitive market provides.

Some argue that ratepayers are disadvantaged when avoided costs are paid to qualifying facilities, because in some cases these facilities can produce electricity at less than the avoided cost price. While it may be true that some QFs could be brought on line at a purchase price below avoided cost, such a price would not be sufficient to bring in other QFs capable of producing power at prices up to the avoided cost price. The point of permitting avoided cost pricing is to encourage the fullest possible efficient development of QF resources that can effectively and economically compete with utility resources. By opening this market, the supply of electricity in increased, which should lower customers' rates over time. Heavy utility reliance on oil and gas fuels to generate electricity has caused rates in California to skyrocket. Avoided cost pricing is intended to stimulate development of

substantial generating capacity that will reduce utility oil and gas consumption. In addition, system reliability is increased by the presence of larger numbers of smaller facilities.

If anything, this Commisison believes that the avoided cost signal to QFs is a conservative one, as it does not include the tangible but hard to quantify "social costs" that are associated with new utility supplies and which are avoided through the purchase of QF power. These "social costs" include the risks associated with imported energy supplies and environmental degradation related to conventional generation. While several parties suggested that we explicitly include "social costs" in the avoided cost calculation, we are not including such factors at this time.

[26] We prefer to recogniz social costs in the general policy judgment that QF

production is competitive at avoided costs. This conclusion is reflected in the terms adopted in this decision that are intended to promote QF development.

We concur with FERC rules which require full avoided cost pricing of power from qualifying facilities. The issue we face now is how to arrive at avoided cost, not whether it should be paid. This proceeding has demonstrated that defining and calculating avoided cost is far from a trivial exercise, involving conceptual, empirical, and technical issues. Some of the issues cannot be resolved without further hearings. However, we resolve most of the major conceptual questions in this decision, and this will simplify the hearings that follow.

Before discussing each of the standard offers in detail, we will discuss the relationship between the offers and the method for using avoided cost principles to derive each of the offers ordered herein.

The first type of offer described below is a standard offer for "as-available" QF power, the price which the FERC indicates should be based upon the "purchasing utilities' avoided costs calculated at the time of delivery." The value of a unit of QF power delivered at any given point in time is equivalent to the cost that the utility would have to incur to produce an equivalent amount of power at that time. This is the short run marginal cost of electricity production in the utility system. As this Commission discussed at length in a recent PG&E rate case, (D.93887, December 30, 1981), the short run marginal cost of utility electricity production is the highest variable operating cost per unit of electricity produced at a given time plus a shortage cost which reflects the effects of the added increment of production [27] on reserve margins and reliability. As these costs are avoided

through purchases of QF power, the purchase price paid to QFs under the first offer is tied to the short-run marginal cost. This will include an "energy payment" equivalent to the utility's marginal operating cost and a "capacity payment" equivalent to the utility's marginal shortage cost. The purchase price, following the avoided short run marginal cost, varies by time of day and time of year.

The FERC rules also call for offers that are made "pursuant to a legally enforceable obligation ... over a specified term ... (with) the avoided costs calculated at the time the obligation is incurred." This type of offer thus takes the form of a long-term standard offer which must be based on projections of avoided costs. Such long term offers give greater certainty to both the QF and to the utility and its ratepayers. Following the same economic principles described above, we order long-term standard

offers which are based on projections of the utility's short-run marginal costs. Such offers reflect the expected short-run marginal cost that the utility will avoid through purchases from QFs at each point in time over several time periods. The price includes an energy component which is tied to short run marginal operating costs in each period and a capacity component which is tied to short run marginal shortage costs in each time period. Energy payments are allowed for up to five years, firm capacity payments for up to thirty years. A levelized payment option is ordered for capacity payments.

A final long-term avoided cost offer described below is based on projected long-run marginal costs rather than short-run marginal costs. These offers should be roughly equivalent over time, since the utility's

short run marginal cost can be expected over time to fluctuate around the utility's long-run marginal cost. The latter [28] is defined as the capital and operating costs of marginal additions to the utility's generation capacity. The avoided cost price offer that is based on the long-run marginal cost will be a more stable pricing alternative and will place system capacity additions derived from QF investments on an equal footing with those derived from utility investments. This long-term resource plan-based price offer for firm energy and capacity will be for periods up to thirty years, with energy and capacity payments tied to the utility's long-run marginal energy and capacity costs.

We note in passing that while long-run standard offers can be based on either projected short-run marginal costs or

projected long-run marginal costs, there is debate on the development of the long-run marginal cost. We will reserve for further review the proper relationship of energy and capacity in the long-run standard offer.

* * *

[72] e. Refusal to Purchase

FERC regulation Section 292.304(f) provides, in part:

> "Periods during which purchases are not required.
>
> "(1) Any electric utility which gives notice [73] pursuant to paragraph (f) (2) of this section will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.

> "(2) Any electric utility seeking to invoke paragraph (f)(1) of this section must notify, in accordance with applicable State law or regulation, each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility."

FERC states that this provision does not override "contractual or other legally enforceable obligations" of the utility to purchase from a QF and that such nonpurchase periods may be taken into account in setting rates for purchases. There is widespread interest in the way this provision will be reflected in the standard offer.

Staff offers a series of recommendations. It proposes that utilities not be allowed to refuse to purchase energy or capacity which is fixed by contract over a duration of obligation, except for conditions of emergency, maintenance, or minimum load. As an alternative, staff suggests utilities may offer the actual lower avoided costs to QFs if actual avoided costs are lower than those sufficient for as-available deliveries. Under the alternative the utility must accept all deliveries tendered by the QF and offer the actual lower avoided cost. Utilities [74] will be limited to 600 hours per year of paying a price lower than the published avoided cost price or refusing deliveries under conditions of maintenance or minimum load. Utilities that choose to pay lower prices would be required to pay prices higher than the published avoided cost price when actual avoided costs are higher than the published price for up to, but no more than, 600 hours per year.

APPENDIX C, ORIG. PGS. 73, 74

Staff further recommends that utilities propose a notification procedure that will provide adequate notice to QFs of times of nonpurchase and prevailing prices. A list of periods of anticipated nonpurchase is suggested so that QFs would be able to schedule maintenance to coincide with such periods. A minimum of 48 hours notice is proposed for QFs with baseload or intermediate-type plants. A minimum of two hours notice is suggested for QFs with peaking-type plants.

Nonpurchases are proposed to occur in the following order of priority: first, small power producers who can inventory fuel; second, topping cycle cogenerators who can bypass the electric generation and save some fuel; third, bottoming cycle cogenerators and small power producers where fuel cannot be stored.

Staff further proposes that each utility be required to present a report in every ECAC proceeding explaining and supporting periods when prices are lower than published or when nonpurchase occurs.

PG&E proposes:

> "Utilities shall not be required to accept power from QFs during (1) emergencies; (2) times of pre-announced maintenance on the utility system which are limited to the [75] shortest possible duration; and (3) operating conditions of minimum load on utility plants, the continued operation of which is necessary to serve anticipated daily load swings. Such minimum operating conditions include operation of geothermal facilities, utility dispatched hydro-electric facilities and firm purchases to obtain optimum use of these resources.
>
> "To account for the availability of economy energy, which is energy purchased by the utility at a price below the Standard Offer published prices, utilities may either:

"a. Calculate their avoided energy cost to include an annually expected number of hours of economy energy. During periods when economy energy is available, the utility shall not refuse to accept QF energy deliveries based upon price; or

"b. Offer the lower avoided cost price to QFs when economy energy is available and only curtail, and not pay for, energy and As-Delivered Capacity (if the QF has chosen that option for capacity payment) made available by a QF which refuses to accept the lower price."

[76] It would limit the number of hours of nonpurchase or lower prices to 600 per year.

PG&E also agrees that a report should be filed in ECAC proceedings (though not as detailed as proposed by staff) and with staff's recommendations regarding notice to QFs and priority of refusal to purchase.

Edison states that it is concerned with the possible impact of paying published avoided costs of QFs when lower cost

energy is available. It indicates that during such periods, the lower cost energy may be substantially below the cost of energy produced from the low sulfur fuel oil. It warns that a utility would be severely criticized if it were unable to meet its public utility obligation to its customers to provide lowest cost power, and an unjustified burden would be placed on the utility shareholder if the avoided cost payments were not recoverable in an ECAC proceeding. It concludes that payment at prices below published avoided cost, when its true avoided cost is less than the published price, is consistent with PURPA and FERC regulations.

SDG&E contends that "if the energy payment tables are properly calculated, the actual avoided costs to the QFs will be properly reflected and paid." It suggests that the problem of nonpurchase of economic reasons can be resolved through proper costing

periods. By adopting a "super off-peak" reflecting anticipated periods of low cost energy, the times when avoided cost energy rates would be so far out of line with actual avoided costs to justify refusal of deliveries would be minimized.

SDG&E does support the ability to pay at less than published costs for certain maximum hours during the year, and accepts 600 hours as reasonable.

[77] SDG&E states that staff's recommended notice requirement is "excessive". It offers two-hour notice for baseload and 30-minute notice for peaking units as "more realistic." It also objects to staff's nonpurchase priority. It argues that "curtailments must be based only on size, from largest to smallest. In an operational emergency, it is impossible to spend time deciding who has fuel capabilities and who does not."

In general, we find that the utilities have interpreted this provision more liberally than apparently intended by FERC. The language of the regulation expressly limits its application to periods when the choice is between a QF and self-generation. There is no recognition of economy energy purchases.

This interpretation is supported by FERC comments:

> "This section was intended to deal with a certain condition which can occur during light loading periods. If a utility operating only base load units during these periods were forced to cut back output from the units in order to accommodate purchases from qualifying facilities, these base load units might not be able to increase their output level rapidly when system demand later increased. As a result, the utility would be required to utilize less efficient, higher costs units with faster start-up to meet the demand that would have been supplied by the less expensive base load unit had it been permitted to operate at a constant output."

This concern does not appear to contemplate economy energy purchases.

[78] This issue must be addressed in the context of the standard offer options described above. The QF may contract to be paid on the basis of "the avoided cost calculated at the time of delivery." The right to not purchase arises only when that cost is less than zero, a negative avoided cost.

The QF may instead contract to be paid based on "the avoided costs calculated at the time the obligation is inccurred." This method yields the sort of "published prices" apparently referred to in the various comments. There is no basis for refusing to purchase from such QFs merely because actual avoided costs occasionally go below published prices. There is just as much of a chance that actual avoided costs will be occasionally

higher than published prices. Allowing for nonpurchase in the first instance without providing for a higher payment when appropriate is unfair. Providing for both higher and lower payments is inconsistent with the purpose of the option to be paid based on avoided costs calculated at the time the obligation is incurred. Therefore this QF should be refused electric purchases only when the avoided cost is negative.

QFs have expressed concern that there may be no maximum number of hours during which refusal to purchase energy may occur. They feel this may result in financing problems (among other problems) since the utilities then are viewed as having an open ended opportunity to refuse purchases. A refusal to purchase would, of course, be subject to Commission review as provided by FERC. A more pragmatic method is required to allay these concerns. First, this decision

will order that refusal to purchase, except in cases of emergency and scheduled maintenance, shall be limited to QFs of 1 MW or larger. Second, a refusal to purchase should only occur when a negative avoided cost occurs. Refusal to purchase should only apply in certain narrowly defined circumstances, unlikely to occur more than 100 hours per year.

* * *

[107]

V. Wheeling

FERC regulation Section 292.306(d) provides for limited wheeling:

> "If a qualifying facility agrees, and electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such energy or capacity is transmitted shall purchase such energy

> or capacity under this subpart as if the qualifying facility were supplying energy or capacity directly to such electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to § 292.304(e) (4) and shall not include any charges for transmission."

[108] In its comments FERC indicates that there are several circumstances in which a QF might prefer that an electric utility with which the purchasing utility is interconnected would make such a purchase - for example, if the avoided costs of the second utility are higher. However, if the first utility does not agree to transmit the purchased energy or capacity, it is not forced to wheel and retains the purchase obligations.

Staff states that the extent of state authority to order wheeling is limited by

federal law by virtue of the preemption doctrine. It points to PU Code Sections 2801-2816 as providing this Commission with limited jurisdiction to order interconnection for the purpose of transmitting energy on behalf of a "private energy producer," assuming that certain specified findings are made. Staff argues that these sections avoid federal preemption because jurisdiction is limited to transmission for the private energy producer's own use and because the transmission is limited to the service area of a single utility. Staff concludes that, although the Commission has no authority to require wheeling when federal jurisdiction attaches, utilities should be urged to consider wheeling requests on a case-by-case basis.

The utility response is varied. PG&E states that staff's position agrees with its view. Edison argues that even transmission on

behalf of a private energy producer is subject to exclusive federal jurisdiction through application of the commingling doctrine. SDG&E focuses on conditions that it proposes to require in the event that QF generation is made available by a wheeling utility.

CEC contends that this Commission should state clearly that utilities are encouraged to wheel. It states that this Commission can and should use our authority to ensure that [109] utilities do not use their monopoly control over transmission lines to hinder QF production. It offers the following statement for our endorsement:

> "The Commission will not tolerate the utilities' use of their control over the transmission system to limit access by small power producers who seek to use the transmission lines to transmit power to a purchaser of the small power producer's energy. Such actions will be considered by the Commission in setting rates for utilities in future ratemaking proceedings, and in evaluating the utilities' imagination and vigor in implementing and pursuing conservation and the development of small power production and renewables."

CEC suggests each utility report regarding requests for transmission service as part of its rate case showing.

Union states that wheeling can be a major factor in promoting cogeneration and small power production. It urges this Commission to strongly encourage utilities to consider all requests to transmit power and to accommodate such requests on a fair and nondiscriminatory basis. It warns that otherwise even such large companies as Union may be discouraged from pursuing opportunities.

NRDC argues that staff's conclusion regarding the extent of our jurisdiction is based on an unnecessarily narrow view of wheeling issues. It recommends that we consider fashioning "narrowly tailored wheeling requirements to further the objectives of PURPA."

CMA addresses specifically the issue of wheeling between two facilities of the same industrial entity. It argues that the principle of simultaneous purchase and sale fundamentally changes the concept of wheeling. It contends that the principle applies whether the resources and load are on the same site or separate sites. CMA observes that the utilities readily accept the same site principle, but reject its extension to separate sites.

[110]

We agree that wheeling is an important concept that can make a material contribution to cogeneration and small power production in California. For that reason we state plainly that each utility's willingness to wheel will be examined in the context of its overall conservation activities in conjunction with general rate case proceedings.

Regardless of utility's willingness to wheel power for its neighbor, each utility, for some reason, appears to limit its cogeneration and small power activities to the confines of its own service territory. This occurs even though locally available generation may not match requirements. Further, some generating sites, while located in other service territories, may still be closer to the buying utility's load center than would alternatives such as out-of-state power purchases. We find that it is not prudent for a utility to fail to pursue an otherwise beneficial facility simply because it is located in another service territory. In addition, this Commission will view with disfavor any actions or inactions by a utility which will interfere with the signing of a contract between a neighboring utility and a cogenerator or small power producer located in its service territory.

In the discussion above we considered whether to limit utility recovery in cases of utility participation in successful cogeneration and small power production ventures. We indicated that such participation should be favored. In relation to wheeling this principle applies to the prospect that a major facility may require utility financing or guarantees in order to be built (a classic "nonstandard" contract) that the "host" utility is unwilling or unable to provide (for example, the utility may already have excess capacity). In this case another utility may be able to participate under terms and conditions that benefit all parties.

The attractive feature of wheeling is that it introduces actual competition into the market. To the extent that competition occurs, the burden of regulation is proportionately reduced.

[111]

Respondent utilities are required to buy energy and capacity from a QF located in the service area of another utility whenever the conditions of Subsection 292.303(d) of the FERC rules are met.

Subsection 292.303(d) is clear that the price paid to the QF by the purchasing utility shall not include any charge for transmission but may be either raised or lowered to reflect the savings or costs resulting from line losses. The discussion accompanying the final FERC rules indicates that the serving utility would collect any applicable transmission charges for wheeling power from the QF and that, in the case of respondent utilities, the rates for these charges would be set under Part II of the Federal Power Act. Transmission charges by the serving utility should take into consideration the extent to

which the QF's power displaces power that would otherwise be transmitted from the utility which receives the QF's power to the serving utility. For example, if all of the QF's power displaces power that would otherwise be delivered by the purchasing utility to the serving utility, the transaction becomes a bookkeeping rather than a physical exchange, and therefore no transmission charges would appear to be justified.
[112]

At this stage of this proceding we are optimistic that the respondent utilities subject to this Commission's jurisdiction will respond to wheeling requests in a fair and nondiscriminatory manner. If our optimism is well-founded, we will need not decide the extent of action needed to encourage wheeling. If our optimism is unfounded, we will take what ever action is appropriate.

In this posture we must necessarily require information to be provided periodically regarding utility actions in this regard. Therefore, we will require each utility to report at the end of January of each year on wheeling performed during the previous year, the parties for whom the wheeling was performed, the terms and conditions applied to the transaction, the technical wheeling arrangements, the status of any pending requests to wheel, and the circumstances relating to any request that was refused.

* * *

[138]

The tariffs which the utilities shall file will be subject to preliminary review by our staff, and accepted for filing on an interim basis. Unique situations should be handled by a deviation procedure under General Order 96-A. We make these tariffs interim in

recognition that interconnection requirements are still evolving. We make no final judgment at this time regarding specific technical requirements necessary to assure operating reliability. We recognize that wide differences of opinion exist as to particular requirements which may need to be the subject of a general order. Accordingly, after six months we shall review these tariffs to assess their effectiveness, and, at that time, shall determine whether more detailed requirements are appropriate.

VIII. Interconnection Costs

A. Introduction

FERC Regulation Section 292.306 provides that each QF shall be obligated to pay any interconnection costs which the State regulatory agency may assess against the QF on a nondiscriminatory basis with respect to other customers with similar load characteristics. The State regulatory agency

shall determine the manner for payment of interconnection costs, which may include reimbursement over a reasonable period of time.

FERC Regulation Section 292.101(b)(7) defines "interconnection costs": [139]

> "'Interconnection costs'; means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an

equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs."

There is an obvious relationship between certain of these costs and the standards of operating reliability discussed above.

B. Positions of the Parties

Staff states that in order to determine what are reasonable interconnection costs it is first necessary to determine what are the minimum acceptable interconnection standards.

Staff recommends that a procedure similar to the special facilities provisions of existing tariff schedules should be established for interconnection costs. Staff proposes that the QF have the option to either: (1) advance to the utility the estimated net installed cost of the

interconnection facilities and also pay the monthly cost of interconnection ownership charges as authorized in the utility's interconnection tariff, or (2) not elect to advance the estimated installed cost of the interconnection facilities and instead pay a monthly combined charge for added facilities as authorized in the interconnection tariff. Such a charge would cover both facilities and ownership costs. With the second option, the [140] customer agrees to pay the net unpaid balance, including interest, of the installed cost of the interconnection facilities, plus removal charges, less estimated salvage value. Staff proposes that CP National Corporation be excused from this approach on account of its status as a buyer of its entire requirements in California. Instead, CP National Corporation could include the method of payment either in its contracts with individual QFs or in separate facilities contracts.

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PG&E agrees with staff's recommendation, with certain modifications. PG&E suggests that when an agreement is terminated, the QF may be entitled to a refund of part of its advance payment to the utility. PG&E proposes that the QF may be required to make an additional payment to cover the cost of the equipment removal and outstanding installation expenses.

Edison states that although staff's list of protective functions is relatively complete, specific instances will require additional equipment, most likely in the cases of large generators. In such cases Edison contends that the need for the equipment will be apparent and the utility and QF will mutually agree that it is necessary. Edison suggests that the QF should pay for the equipment in such cases.

SDG&E states that the costs of interconnection as specified by the utility should be borne by the QF. If the Commission finds that SDG&E's interconnection guidelines are not reasonable, SDG&E is "willing to discuss revisions" to its interconnection guidelines.

SDG&E objects to staff's proposal that the QF have the option to obligate the utility to make a capital investment for interconnection costs. SDG&E states that to require the utility to add this funding burden to its other capital requirements negates one of the largest benefits of congeneration. SDG&E suggests that utility funding be at the option of the utility.

[141]

C. Discussion

The basic proposition is straightforward. Each QF is responsible for the cost of interconnection which exceeds the

cost the utility otherwise would incur to connect the QF as a customer. The costs of interconnection borne by the QF shall be only those costs necessary to meet the minimum reliability standards discussed above. The cost of additional requirements imposed by the utility shall be borne by the utility.

We are satisfied that staff has provided a sound payment basis, as modified by PG&E. SDG&E's concern regarding the possible financial burden of utility financing can be taken into account in calculating avoided costs, if an evidentiary basis can be shown.

Some QFs, particularly smaller ones, may require distribution-type line extensions. Wherever such line extensions are comparable to those serving residential or commercial customers, the charges to the QF should also be comparable to those charged

other utility customers, including refunds to customers. Distribution-type line extensions costs presently are covered in utility Tariff Rules Nos. 15, 15.1 and 15.2. Unless the QF's load characteristics on any line extensions required for the QF are different than for regular utility customers, the line extension costs should be the same for each to avoid discriminatory pricing practices.

* * *

Excerpts from California PUC Decision
No. 82-12-120,
dated December 30, 1982

O P I N I O N

Summary

Decision (D.) 82-01-103, January 21, 1982, established guidelines for utility purchases of electricity from cogenerators and small power producers. That decision ordered utilities to file five standard price offers each of which would be a complete contract which small power producers could sign without negotiation. The five offers were to meet the varied needs of different qualifying cogeneration and small power production facilities (QFs).

* The as-available offer pays an energy payment and a capacity payment in ¢/kWh varying by time of delivery. The payment is derived from utilities' short-run avoided costs (i.e., variable oprating costs plus shortage value). This offer is similar to a spot market purchase in a competitive environment and requires no long-term contract-type commitment on the part of the QF.

* The firm capacity offer is like the as-available except that payments for capacity are based on specific performance

requirements being met by the QF (including availability or output requirements). The capacity price may be fixed for up to 30 years. The offer provides some pricing certainty for those who can meet the specific performance criteria.

* The less than 100 kW offer is similar to the as-available, except for simplified requirements for the small facilities.

* The five-year forecast offer fixes energy prices for five years, providing more price certainty.

* The long-term resource plan based offer bases prices on new utility resources (as opposed to short-run avoided costs). It may be used to establish price more firmly for longer periods and to pay for the full value of new resources.

* * *

[113] The record indicates that at this time adjustments for line losses for remote sites is beyond our current capacilities. We will therefore suspend the use of specific line losses for remote sites until the problem is better understood. As part of the studies required of utilities, we will ask for an analysis of how to identify remote QFs and how to reflect a different loss rate. Until such studies are performed, remote QFs will not have individual line losses adjustments.

PG&E suggests that individual line losses should be established. This approach would not comply with D.82-01-103. The individual determination of line losses would create great complexity and would very likely result in frequent disputes between the utility and QFs. Aggregate line loss determinations are appropriate at this time.

4. Transformer Losses

An issue was raised about whether transformer losses should be included in the avoided cost payment, and if so, how that loss should be determined. The staff suggests an appropriate solution: simply place the meter on the utility side of the transformer, thereby automatically accounting for the transformer losses in the meter reading. We will adopt this recommendation. If a QF desires to have a meter on its side of the transformer, it may negotiate a transformer loss rate with the utility.

D. Refusal to Purchase and the Hydro Spill Rate

One of the more complex issues relating to energy payments regards the periods in which a utility may refuse to purchase from QFs or offer lower prices to reflect current conditions in the utility system. As described earlier, price [114] is established for electricity purchases for a time period based on projected average marginal costs. The actual avoided costs incurred will vary throughout the period, varying around the average established.

There are certain conditions in which the actual avoided costs deviate so significantly from the average that special treatment may be warranted. In particular, D.82-01-103 found that when the utility actually incurs costs by purchasing energy from a QF (a "negative avoided cost" condition), the utility should have the right to curtail QFs. In D.82-04-71, the Commission

also concluded that when a utility must spill water over its own hydroelectric facilities in order to purchase from QFs, a lower price is appropriate. The decision did not, however, permit a lower price to be established during periods when economy energy is purchased or when avoided costs are positive. Anticipated economy purchases were to be averaged in the avoided cost applied for the entire time period.

* * *

Excerpts from California PUC Decision
No. 83-09-054,
dated September 7, 1983

A.82-04-44, et al. ALJ/rr/jn *

I N T E R I M O P I N I O N

These proceedings involve adopting standard offers based on long-run avoided costs for power purchase contracts between the three largest electric utilities and qualifying facilities (QF). The utilities are: Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric Company (SDG&E).

Before explaining the procedural history which has brought us to this point, we think it is constructive to explain briefly why we have pursued developing such standard offers in view of the standard offers in-place which pay QFs for their power based on actual short-run utility avoided costs.

I. Summary of Decision

This decision authorizes what is termed Standard Offer #4, which has different payment options for QFs, all of which are based on

forecasts of the utilities' resource mix and costs. The three payment options under Standard Offer #4 resulted from negotiations. A negotiating conference, which lasted five weeks, was held at our direction, with vigorous participation by utilities, QFs, and our staff. We have committed to hold evidentiary hearings, which almost all parties desire. However, there is substantial agreement among utilities, QFs, and our staff that until a more permanent solution is found for the complex task of fairly valuing and pricing QF power over the long-run, Standard Offer #4, with three payment options, should go into effect.

We undertook the negotiating conference in the hope of coming closer to an interim solution which, while not perfect from all perspectives, could be useful for QFs and utilities. While some may have hoped to accomplish more than the scope of the

consensus reached, or they would have preferred different results, we think the negotiating conference was extremely fruitful. [3] The negotiated standard offer and three payment options are approved, with some reasonable restrictions on their use set by us under our prerogative.

Standard Offer #4, at this juncture, is interim in the sense it may ultimately be replaced with a different costing methodology, contract terms, etc. However, until that happens, it may be fully relied on by utilities and QFs who find the options useful. Those who contract under interim Standard Offer #4 will not be subject to having terms or prices changed later, except as narrowly and specifically ordered by this decision. Any changes made to this standard offer in the future will only apply to those contracting after such changes. Potential QFs

who find they cannot use Standard Offer #4, as approved today, still have the option of pursuing a negotiated nonstandard contract with utilities.

II. Background

Utilities' short-run avoided costs have proven to be more volatile than many observers would have guessed. We have seen a drastic run-up in fuel oil and gas prices, followed by a moderate decline in oil prices. The QF industry contends that the price uncertainty posed under the existing as-available and firm capacity standard offers, both based on short-run avoided costs, makes it extremely difficult to arrange financing for potential QF projects. QFs tell us that those who hold the financing purse-strings, both lenders and equity investors, are reluctant to commit capital when a project's payment stream is so uncertain. Our Decision (D.) 82-01-103 in OIR 2, issued January 21, 1982, recognized the

need to pursue [4] developing standard offers based on long-run avoided utility costs (page 67, mimeo.). Oil and gas prices were steadily rising when that decision was issued, and although the three largest electric utilities were ordered to file applications with proposed standard offers based on long-run avoided costs, most of our attention and that of the QF industry was directed to perfecting standard offers based on short-run avoided costs. Many assumed oil prices would continue to rise; few seemed to believe they would start a decline. As oil prices started to decline the intensity of interest in standard offers which would produce prices based on long-run (and presumably less volatile) avoided costs correspondingly increased.

If we do not adopt a standard offer based on long-run avoided costs as an alternative to the existing standard offers, the pressure for nonstandard contracts between utilities and

QFs could steadily increase. Such nonstandard contract negotiations pose problems for all: QFs typically ask for variations of up-front price security or certainty so they can finance projects, and utilities are faced with ensuring the nonstandard contract has suitable terms to make it a secure venture for them and their ratepayers; further, operating under our regulation, utilities are concerned about ultimate cost recovery, and worry that the prudence of nonstandard contracts may be successfully challenged in their energy cost recovery proceedings. Also, the long-term value of new QF capacity in the utilities' resource plans is not fully reflected by the existing standard offers which base prices on fluctuating short-run avoided utility cost (see D.82-01-103, p. 67). It is, then, in everyone's interest that a standard offer based on long-run avoided cost be adopted.

* * *

[21]

V. The Structure of Standard Offer #4 and Future Contract Language Consistency

This opinion will address what is called Standard Offer #4, which contains several payment options. Standard Offer #1 was adopted by D.82-12-120, and is for as-available energy payments; #2 is for firm capacity, and #3 is for smaller QF projects (under 100 kW). The Standard Offer #4 contracts proposed by each of the three utilities has some common contract terms that apply for all options, and specific terms covering the individual payment options. The filed contracts are complete with the agreed upon forecasts, upon which prices will be paid.

Each utility chose its own format and contract language, with the goal, however, of all being consistent in substance (with the exception of certain agreed to utility specific terms, such as curtailment). As experience is gained with standard offers, and

QF power purchase contracts generally, uniform standard contract language should be used by all utilities, except for terms which must clearly be utility specific because of substantitive differences. The convenience of standard language will greatly aid those who must review standard offers. We are disappointed this could not have been done for Standard Offer #4 in the context of the negotiating conference, but it appears time did not permit it. Rather than to simply pick one of the utilities' contracts and order that language used by the others, we will direct the utilities to work together with our staff, in proposing one form of Standard Offer #4 with uniform language (except where terms must be utility specific). Six months will be allowed for this undertaking, and the product shall be presented during the subsequent hearings for review.

* * *

[36]

D. Curtailment Provisions (Under All Payment Options)

The negotiated curtailment provisions for Standard Offer #4 are utility specific, with PG&E's provisions consisting of the following 2 options:

a) Curtailment under "negative avoided cost" conditions and a lower "hydro spill rate" under hydro spill conditions with no hourly limit. This option refers directly to this Commission's definition of negative avoided costs and hydro spill conditions.

b) A limit of 1,000 hours of real time prices per year for negative avoided cost, hydro spill and non-oil/gas units at the margin. This second option requires some further explanation, as PG&E explains:

> "PGandE will not curtail the QF when these conditions occur, but will instead offer to continue purchases at a price equal to the current actual avoided energy cost. The QF can then make its own operating decisions; PGandE and ratepayers will be indifferent. PGandE will limit the 1,000 hours to

off-peak periods, and increase the price in the other off-peak hours to account for the fact that these low-cost periods are no longer being averaged in.

[37] "PGandE's unique system means it will have to have maximum operating flexibility in the coming years to efficiently utilize the available resources. The 1,000-hour option helps provide this necessary flexibility while remaining faithful to the avoided cost framework. SCE and SDGandE are not providing the opportunity for the QF to remain operational and receive actual avoided costs, but are instead offering annual hourly curtailment limits. PGandE does not believe such an approach is appropriate in its case, and would object to one being imposed". (PG&E's Amended Application, Exhibit A, pages 11-12).

SDG&E's negotiated standard offer includes provisions to curtail QF production for up to a total of 300 off-peak hours per year where such purchases result in "negative avoided cost" to SDG&E "as such term is defined by the CPUC (SDG&E's Amended Application, page 22)."

Edison's offer curtails the QFs production for up to 300 off-peak hours when:

> "(i) purchases would result in costs greater than those which Edison would incur if it did not purchase energy from seller but instead utilized an equivalent amount of energy generated from another Edison source (emphasis added), or
>
> "(ii) the Edison Electric System demand would require that Edison hydro-energy be spilled to reduce generation". (Edison's Amendment, page 26)[5]

In D.82-01-103, D.82-04-071, and D.82-12-120, we defined "negative avoided costs" as a situation where, due to operational circumstances, purchases from QFs would result in costs greater than [38] those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself. We cite

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5 The phrase "generated from another Edison source" is interpreted (by both SCE and the Commission) to exclude economy energy purchases. Hence, it conforms with Commission policy on this issue.

such a condition as being when a baseload or large oil-fired intermediate load plant is shut down at night due to an excess of QF electricity but then cannot be restarted and brought up to its rated output for the next day's peak load, thus necessitating instead the start-up of a plant with very high generating costs (e.g., a gas turbine peaker) or an expensive emergency purchase of capacity. In D.82-04-071 the Commission concluded that, while curtailment was not appropriate for hydro spill conditions, a lower "hydro savings" price is appropriate. The decision did not, however, permit a lower price to be estalished during periods when economy energy is purchased or when avoided costs are positive. Anticipated economy purchases were to be averaged in the avoided cost applied for the entire time period. Proposals to restrict the number of hours that

curtailment and hydro spill conditions apply were denied in D.82-01-103 and D.82-04-071. However, in D.82-12-120 we directed utilities to undertake studies which would be considered in reviewing future proposals to establish such limits.

Only PG&E's curtailment option a) conforms with our narrowly defined negative avoided cost and hydro spill conditions established for Standard Offers contracts #1 and #2. We acknowledge the nonconformity of PG&E's option b) and the other utilities' curtailment provisions with our previous decisions. However, we consider these disparities as part of the negotiation process and integral to the parties arriving at a negotiated "package". We alert parties that these provisions will be reviewed and evaluated for prospective standard offers in evidentiary hearings.

E. The "Regulatory Authority" Clause

Edison and SDG&E have what are commonly termed "Regulatory Authority" clauses, which allow for changing contract terms if directed by a regulatory agency. Edison's reads as follows:

> "This Contract shall at all times be subject to such changes as any regulatory agency may direct in the exercise of its jurisdiction. If there is any conflict between the provisions of this Contract and any changes directed by such regulatory agency, the Parties shall amend this Contract in a manner consistent with such regulatory changes."

Both utilities indicated they include this clause consistent with prior Commission directives with respect to earlier standard offers. PG&E indicated it was willing to drop this clause because it seems incompatible with a long-term forecast based and binding contract, particularly if this Commission clearly intends to allow utility cost recovery for prices paid under standard offer contracts.

In view of our holding that contracts entered under Standard Offer #4 will not be subject to retroactive change based on prospective developments in the continuing saga of pricing QF power, we think the regulatory authority clause should be deleted. In other words, the quid pro quo for giving QFs certainty with respect to all contract terms, and eliminating the regulatory authority clause, is that QFs may not freely switch to other contracts later, until their contract term is up, if subsequent contracts or terms appear more favorable. Thus, we are really exchanging certainty of contract sanctity for certainty of commitment, and given our reaffirmation that cost recovery will be allowed utilities for all standard offer power purchase contracts, we think this only fair. QFs contend that with the regulatory authority clauses in the contracts

of Edison and SDG&E there will be insurmountable hesitation by lenders because of [40] uncertainty. In ordering the clauses removed we recognize that we cannot order retroactive changes to interim Standard Offer #4 contracts but, given the restrictions placed on the use and availability of this negotiated standard offer, we are willing to commit to that loss in flexibility.

* * *

Excerpts from California PUC Decision
No. 84-03-092,
dated March 21, 1984

A.82-03-26, et al. ALJ/rr

[58] b. Developments Since November 1983

Since our first review of PG&E's petition, we have been concerned that there have existed "special facts" to which only PG&E has had access.

In January of this year, we were informed by the staff of a briefing of the staff by PG&E in November, 1983. Details of this briefing accompanied a proposed Order Instituting Investigation (OII) into transmission constraints on QF development in PG&E's northern California service territory.

[59] According to the staff, PG&E at this briefing informed the staff that limitations on its transmission system were going to severely restrict QF development in the region. To accommodate a potential 800 MW of QF generation, PG&E represented to the staff that transmission system improvements

would be required in the estimated amounts of $130 million for bulk system upgrades and $100 million for local area improvements.

This information, of course, has not been verified nor included in any formal pleading or Commission proceeding. In PG&E's recent general rate case, the only acknowledgment of any constraint on its transmission system related to wind development in Solano County. In that case, staff had recommended a rate of return penalty for PG&E's refusal to reallocate 218 MW of capacity to other wind developers in the area if the two wind developers to which this capacity had been committed could not meet their contractual obligation to proceed by January 1984. We rejected staff's recommended reallocation on the grounds that our first come, first served approach in allocating transmission resources to QFs was not intended to favor one technology over another. We

further stated that "before committing transmission resources to QFs, we would want to ascertain whether Northwest Power would be displaced as a result." (D.83-12-068, p. 331.) As we discuss below, PG&E has now taken this statement out of the context of the limited record we had before us in the rate case, applied it to its alleged current transmission constraints, and concluded that it cannot commit any transmission capacity to northern California QFs at all until a further Committion order permitting it to do so.

[60] In addition to failing to alert the Commission of its transmission constraints in any proceeding or pleading, PG&E has also chosen its own method for dealing with a QF's cost liability for future system alterations, rather than the one approved by the Commission. As we stated earlier, guided by PG&E's testimony in this proceeding, we had felt it sufficient to require the utilities,

"prior to the standard offer being signed," to identify "any future system modifications planned or assumed by the utility, the particular changes likely to be charged to the QF, and the basis for these charges being imposed." (D.83-10-093, at p. 60; see also, Ordering Paragraph 13.) Obviously, under PG&E's current scenario, the costs to the QF for system upgrades could be staggering, and without any specification of that liability in the manner which we required, the effect on financing or development could be quite chilling.

PG&E, however, has addressed the question of future system upgrades by adding language to its standard offers which has never been presented to or approved by this Commission. In response to concerns expressed by the Commission President, the assigned Adminstrative Law Judge (ALJ) contacted PG&E for more information on this

development. On February 15, 1984, a PG&E attorney responded by letter. Among other things, the letter included the following representations:

1. "Transmission studies conducted by PGandE indicate the current and future existence of transmission capacity limitations in this region. Transmission limitations occur in both the bulk and area system."

2. The region where these limitations "have been identified" include "Humboldt, Shasta, De Sabla, Colage, Drum, Sacramento, and the northern part of Stockton Divisions."

[61] 3. Bulk transmission capacity limitations occur on PG&E's 230 and 500 kV transmission system, and area transmission limitations occur on PG&E's 230, 115, and 60 kV system. PG&E relates these limitations wholly in the case of area limitations and in part in the case of bulk transmission limitations to QF generation exceeding available transmission capacity.

4. PG&E cannot "unilaterally" commit transmission capacity to QFs or allocate costs to QFs without Commission approval or a Commission evaluation of its statement in D.82-12-068 that "before commiting transmission resources to QFs, [the Commission] would want to ascertain whether Northwest power would be displaced as a result."

According to the letter, PG&E decided, based on the above circumstances, that its best course of action was to develop "language for inclusion in its power purchase or other agreements with QFs in the affected regions." The language is not included in the power purchase agreement only if "the QF has been advised in a letter or through the interconnection study process."

Thus, while not able to "unilaterally" commit transmission capacity to QFs, PG&E has been capable of "unilaterally" adding the following language to its standard offers. PG&E claims the language is merely a formal reiteration of the QFs' existing

obligations under PURPA and Public Utilities (PU) Code § 2813. No mention is made, however, of our orders and decisions in this proceeding. The added provision states:

[62] "Due to the location and the point of interconnection of the Facility to PGandE's system and the limited availability of transmission capacity on PGandE's existing system, Seller may incur interconnection costs associated with providing reinforcements and/or additions to PGandE's transmission system to accommodate Seller's power deliveries. Notwithstanding the execution of this Agreement or any provision herein, Seller's right to be paid for and deliver power to PGandE shall be contingent upon Seller's payment of all interconnection costs allocable to Seller in accordance with the applicable PGandE tariff or appropriate CPUC order. PGandE shall determine as soon as it is practicable those reinforcements and/or additions to its transmission system necessary to accept power deliveries from Seller and the estimated costs associated therewith." (Emphasis original.)

APPENDIX F, ORIG. PGS. 61, 62

[63] According to PG&E's letter, this language has been added to 12 standard offer contracts all involving projects of 10MW or more, for a total of 248.6 to 255.6 MW. While the majority of these contracts have been identified as Standard Offer No. 4 constracts, we note that our orders involving future line and system upgrades adopted in this proceeding were made specifically applicable to Standard Offer No. 4 by Ordering Paragraph 1.f. of D.83-09-054. PG&E did not include in its letter the number of contracts to which this clause was not added due to a "letter of understanding."

PG&E appears to be challenging the entire foundation of our standard offer procedures. It seems unnecessary to repeat, but the very corner stone of these proceedings and OIR 2 is a standard offer whose terms are approved by this Commission and are available to any QF as approved. A negotiated offer

only results from the QF, not the utility, finding the standard offer unacceptable and wishing to alter its terms. This principle was clearly stated in D.82-01-103 and has never been changed: "The standard offer is a choice of contract terms at the QF's sole option." (Emphasis added; D.82-01-103, at p. 148.)

In keeping with the above finding, Ordering Paragraph 25 of D.82-01-103 directed that the "standard offer shall be available to all QFs for acceptance and shall be consistent with the terms and conditions provided for in this decision." The offer was to "remain in effect until further order of this Commission." By Ordering Paragraphs 2 and 11 of D.82-01-103, the utilities were to file by application Standard Offers Nos. 1, 2, and 3, for this Commission's review for their compliance with D.82-01-103. The only [64] terms to be included in a standard offer

therefore were to be those authorized by D.82-01-103, as modified by D.82-04-071, and "further order of this Commission." With respect to Standard Offers Nos. 1, 2, and 3, such further orders have included only D.82-12-120, D.83-10-093, and this decision.

Thus the purpose of our standard offer approach has not only been to fulfill legal obligations imposed by PURPA, but also to place the QF and the utility on an equal footing with respect to a QF's power sales. Information known only to the utility was not to be used to change the terms of a standard offer and the QF was to be certain of a market for its generation on terms reviewed and approved by this Commission.

While certain issues relating to the standard offers had yet to be covered by this order at the time PG&E was adding the above language, provisions governing interconnection standards and costs were not among them. Although PG&E refers in

its letter to PURPA and the code, our interpretation and application of those laws are contained, with respect to interconnection, in D.83-10-093, an order which is as binding on PG&E as those statutes. While PG&E's Tariff Rule 21 correctly refers to the QF's obligation to pay for system upgrades, that language and any related provision of PG&E's standard offers or special facilities agreements was to be subject to the following limitations of Ordering Paragraphs 12 and 13 of D.83-10-093:

[65] "12. The utilities' tariff rules and standard offer provisions governing interconnection costs and special facilities agreements shall require the following:

* * *

"f. The QF shall be responsible for the costs of only those future system alterations which are necessary to maintain this Commission's adopted interconnection standards for the QF's particular interconnection facilities. Should an upgrade not be directly required by or beneficial to the QF, the QF shall be treated like any other customer on the utility's system."

* * *

"13. Each utility shall provide to the QF, prior to the standard offer being signed, all relevant tariff rules governing interconnection costs as well as the identification of any future system modifications planned or assumed by the utility, the particular changes likely to be charged to QF, and the basis for these charges being imposed."

[66] References to neither these orders nor their requirements are contained in PG&E's above-quoted contract provision or its letter. Instead of following the guidelines of Ordering Paragraph 13, PG&E merely states that it will determine "as soon as practicable those reinforcements and/or additions to its transmission system, necessary to accept power deliveries from Seller and the estimated costs associated therewith." It does not appear that PG&E demonstrated, "prior to the standard offer being signed," what those charges were likely to be or the basis for imposing them on any QF.

In addition to unilaterally adding language to its standard offer in violation of D.82-01-103 and reciting requirements which do not follow the direction of our orders in D.83-10-093, PG&E has also based its added provision on a fact which has never been presented, adduced, or proved in

any Commission proceeding -- "the limited availability of transmission capacity on PGandE's existing system". To the contrary, in this proceeding, PG&E's witness testified that future construction on the utility's system could be identified 5 to 10 years in advance. While acknowledging that "unpredictable events" (Tr. 1395) might affect this estimate, the 5 to 10 year period was one with which the witness felt "comfortable." (Tr. 1360.)

While this matter has been submitted since November, 1982, the fact remains that the record was little more than one year old when PG&E first revealed its transmisison system problems to our staff. Despite Clerk's testimony and PG&E's acknowledgement that its current required construction could take five years to complete, PG&E maintains that it has been unable to identify what is required and what a QF's cost responsibility might be.

[67] The need for extensive changes in PG&E's transmission system and the commencement of QF development in northern California are also events which should hardly have been "unpredictable." The roots of this proceeding date back to December 10, 1979, when we first adopted avoided cost pricing in D.91109 for cogeneration facilities and urged the utilities to promote the development of alternate resources. We doubt, too, based on the record and PG&E's current statements, that, unless PG&E is seriously undermanaged or mismanaged, the current state of its transmission system was not known to PG&E at the time of hearings in this proceeding or, at least, at the time of its recent general rate case. Nevertheless, PG&E feels no compunction about using one of our statements based on the limited record in its general rate case as a basis for refusing to commit any transmission line capacity to QFs.

We must now consider the proper recourse against PG&E for its actions.[2] As stated previously, the staff has proposed an OII into the limitations, if any, of PG&E's existing transmission system.

An OII, however, would suggest that our problems with PG&E are merely of a technical, rather than a regulatory nature. Further, an OII would imply that the burden of demonstrating the existence of PG&E's alleged transmission limitations is on the Commission, rather than on PG&E who has apparently already manipulated its "special facts" to the detriment of QF development in northern California. Assuming that PG&E was not aware of its [68] transmission

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2 We note also that these actions include PG&E's current interpretation of its provision governing power deliveries from the QF in the manner which differs from that ordered by the Commission in Ordering Paragraph 8(f) in D.83-10-093.

limitations during hearings in this proceeding or its general rate case, PG&E, of course, should have sought modification of its standard offers based on new facts either by a petition to reopen this record or a new application. Such steps would, of course, have properly placed the burden of proving these facts and the basis for any change in the standard offers or our policy on PG&E. In the case of an OII, PG&E, having already made the changes it desires in its standard offer, would no doubt be in no hurry to respond to data requests or develop its own testimony "without first hearing from staff." While we believe that there are important technical and policy issues to be addressed in an OII on the transmission operations of PG&E and other California utilities, it is inappropriate to issue one in response to the problem at hand.

Under these circumstances, a different course of action is appropriate at this time. PU Code § 2113 provides as follows:

> "Every public utility, corporation, or person which fails to comply with any part of any order, decision, rule, regulation, direction, demand, or requirement of the commission or any commissioner is in contempt of the commission, and is punishable by the commission for contempt in the same manner and to the same extent as contempt is punished by courts of record. The remedy prescribed in this section does not bar or affect any remedy prescribed in this part, but is cumulative and in addition thereto."

[69] Under the authority of this provision, we will issue an order for PG&E to show cause at a hearing date to be set by that order why PG&E should not be held in contempt for violation of Commission D.82-01-103 and D.83-10-093. The order to show cause will also consider PG&E's apparent violation of Rule 1 of the Commission's Rules of Practice and Procedure. That rule provides as follows:

> "Any person who signs a pleading or brief, enters an appearance at a hearing, or transacts business with the Commission, by such act represents that he is

> authorized to do so and agrees to comply with the laws of this State; to maintain the respect due to the Commission, members of the Commission and its Administrative Law Judges; and never to mislead the Commission or its staff by an artifice or false statement of fact or law."

In the meantime, however, we will direct PG&E to follow the letter and spirit of our decisions. PG&E will be prohibited from adding the contract language quoted above to any standard offer or related "special facilities" agreement or refusing to sign any standard offer contract or related "special facilities" agreement in the absence of such language or a similar "letter of understanding." To the extent that such a provision has been included, in any signed standard offer, accompanying letter, or related "special facilities" agreement that term is to be considered null and void as of

the date [70] of the contract signing.[3] Similarly, PG&E will be prohibited from establishing a maximum rate of power delivery based on the QF's anticipated maximum rate of deliveries to PG&E. A provision in a signed standard offer based on this improper standard is also considered null and void as of the date of contract signing. PG&E will be directed to replace the incorrect figure with one based on Ordering Paragraph 8.f. of D.83-10-093.

In addition, PG&E will be directed to comply specifically with Ordering Paragraphs 8.f., 12.e., and 13 of D.83-10-093

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3 We note that, depending upon the circumstances, a QF signing a standard offer with PG&E may have its interconnection cost responsibilities enumerated in a separate special facilities agreement as specified in PG&E's tariffs. No matter what the form, this Commission's authority, as recognized in Ordering Paragraph 12 of D.83-10-093, extends to any agreement designed to set forth the standard offer and tariff provisions approved by this Commission. Our orders, therefore, are equally binding on the terms used in such agreement.

in signing standard offers and supplying information to QFs. It is clear from PG&E's letter of February 15, 1984, that the utility to some extent has studied the future system alterations that may be the responsibility of those QFs in whose standard offers PG&E placed the above-quoted provision or who were similarly advised "in a letter or through the interconnection study process." PG&E shall provide these QFs with the information required by Ordering Paragraph 13 to the full extent of its availability. PG&E shall also inform these QFs of all relevant studies underway or planned and shall provide these studies as they become available. We wish to ensure that these QFs obtained all of the information to which they were entitled prior to the standard offer being signed.

We note that we can now better understand the reason for IEP's request that QFs not be held liable for any costs

associated [71] with a utility bulk transmission line upgrade. While IEP's position was not in keeping with the record in this case, the circumstances which have recently come to light with respect to PG&E's transmission system suggest that we reconsider our rules governing interconnection and interconnection costs.

* * *

[81] Findings of Fact

1. This order is the third decision in A.82-03-26, A.82-03-37, and A.82-03-78. The order is necessary to consider those issues not addressed in D.82-12-120 and D.83-10-093 and the merits of petitions for modification of those two decisions.

* * *

[88] 46. PG&E has failed to comply with Ordering Paragraphs 12.e. and 13 and related discussion in D.83-10-093 and Ordering Paragraphs 2 and 25, Finding 26, and related

discussion in D.83-01-103 by failing to follow the procedures and the standard offer language specified in those orders and by adding the following language to its standard offers:

> "Due to the location and the point of interconnection of the Facility to PGandE's system and the limited availability of transmission capacity on PGandE's existing system, Seller may incur interconnection costs associated with providing reinforcements and/or additions to PGandE's transmission system to accommodate Seller's power deliveries. Notwithstanding the execution of this Agreement or any provision herein, Seller's right to be paid for and deliver power to PGandE shall be [89] contingent upon Seller's payment of all interconnection costs allocable to Seller in accordance with the applicable PGandE tariff or appropriate CPUC order. PGandE shall determine as soon as it is practicable those reinforcements and/or additions to its transmission system necessary to accept power deliveries from Seller and the estimated costs associated therewith." (Emphasis original.)

47. The language quoted in Finding 46 above was never made part of PG&E's standard offers submitted in this application filed in response to Ordering Paragraphs 2 and 11 of D.82-01-103 nor has the provision been submitted as part of a new application or other formal pleading requesting amendment of PG&E's standard offers. The Commission therefore has never reviewed or approved the quoted language.

48. "The limited availability of transmission capacity on PGandE's existing system" is a fact which has never been presented, adduced, or proved in any Commission proceeding and which conflicts with the record in this case.

49. The development of QFs in northern California and the current state of PG&E's transmission system should not have been "unpredictable" events.

50. The statement in D.82-12-068 that "before committing transmission resources to QFs, [the Commission] would want to ascertain whether Northwest power would be displaced as a result" must be read within the context of the actual record on which it was based. This statement was not intended to serve as the basis for PG&E's refusal to commit any transmission line capacity to QFs.

[90] 51. An OII is an improper response to violations of our orders in this proceeding and OIR 2.

52. Under the authority of PU Code § 2113, it is appropriate to issue an order for PG&E to show cause why PG&E should not be held in contempt for violation of Commission D.82-01-103 and D.83-10-093 as described in this decision and the preceding findings. The order to show cause should also consider whether PG&E should be held in contempt for violation of Rule 1 of the Commission's Rule of Practice and Procedure.

* * *

[99] 19. An order to show cause why PG&E should not be held in contempt as provided under PU Code § 2113 shall issue for PG&E's failure to comply with Commission ordering paragraphs, findings, and related discussions in D.82-01-103 and D.83-10-093 and Rule 1 of the Commission's Rules of Practice and Procedure as described in this decision. The ordering paragraphs include Ordering Paragraphs 2, 11, and 25 of D.82-01-103 and Ordering Paragraphs 8.f., 12.e., and 13 of [100] D.83-10-093. At the hearing, PG&E shall also be required to demonstrate (1) whether and the extent to which utility customers comparable to QFs have ever been required to pay for PG&E bulk and area transmission system improvements in the past, (2) the specific instances when this situation has occurred, and (3) the cost allocation which has been employed.

* * *

APPENDIX F, ORIG. PGS. 99, 100